ORIGINAL

GALLAGHER & KENNEDY
P.A.
ATTORNEYS AT LAW

MICHAEL M. GRANT
DIRECT DIAL: (602) 530-8291
E-MAIL: MMG@GKNET.COM

0000140140

2575 EAST CAMELBACK ROAD
PHOENIX, ARIZONA 85016-9225
PHONE: (602) 530-8000
FAX: (602) 530-8500
WWW.GKNET.COM

RECEIVED
AZ CORP COMMISSION
DOCKET CONTROL
2012 OCT 22 PM

October 22, 2012

Arizona Corporation Commission
DOCKETED
OCT 22 2012
DOCKETED BY

HAND DELIVERED

Docket Control
Arizona Corporation Commission
1200 W. Washington St.
Phoenix, AZ 85007

Re: *Arizona Electric Power Cooperative, Inc. ("AEPCO"); The Future Role of Apache Station; Docket No. E-01773A-09-0472*

Dear Sir or Madam:

In response to Liberty Consulting Group's recommendations and the Final Ordering Paragraph at page 17 and the First Ordering Paragraph at page 18 of Decision No. 72055 dated January 6, 2011, enclosed are the original and 13 copies of AEPCO's study concerning The Future Role of Apache Station.

Very truly yours,

GALLAGHER & KENNEDY, P.A.

Michael M. Grant

By:
Michael M. Grant

MMG/plp
10421-59/3166305
Enclosure

cc (w/enclosure): Steve Olea, Director, Utilities Division (delivered)

Original and 13 copies filed with Docket Control this 22nd day of October, 2012.

ARIZONA ELECTRIC POWER COOPERATIVE, INC.

The Future Role of Apache Station

October 2012

Introduction

In Decision No. 72055 dated January 6, 2011 (the "Decision"), the Commission issued its Opinion and Order concluding its action on the Arizona Electric Power Cooperative, Inc. ("AEPCO") Application for Rate Increase which was filed on October 1, 2009.

In ordering paragraphs at pages 17-18 of the Decision, the Commission instructed AEPCO (1) to file an Action Plan on Liberty Consulting Group's recommendations—one of which was to conduct and file a study concerning the future role of the Apache Station and (2) to include in that study "the potential rate impacts...[of EPA] rulemakings regarding mercury emissions, coal ash, and any other known or pending EPA regulatory actions that could impact the Station, AEPCO, and its customers and provide recommendations...regarding potential methods for mitigating the Cooperative and its customers' exposure to those rate impacts..."

This Study—"The Future Role of Apache Station"—is filed in relation to the requirements of those ordering paragraphs.

Background

AEPCO owns and operates the Apache Generating Station which is located in Cochise, Arizona ("Apache Station"). Apache Station has a total net capacity of 558 MW, which consists of three steam turbine units and four gas turbine units. Steam Turbine Units 2 and 3 ("Units ST2 and ST3")—the subject of this report—are coal-fired units with a net capacity of 175 MW each and account for the vast majority of the station's output. Steam Turbine Unit No. 2 was placed in service in 1978 and Steam Turbine Unit No. 3 followed in 1979.

Typically, units of this size would have been fired by natural gas. But, instead, Units ST2 and ST3 were designed for coal firing due to restrictions on natural gas capacity additions contained in the National Energy Act. Later, and following removal of that federal restriction, the units were modified in 1989 and 1992 in order to operate as coal- or natural gas-fired units.

When constructed, the design life of these types of units was generally 30-40 years. In August of 2003, however, Burns & McDonnell prepared a Condition Assessment Report for Units ST2 and ST3. Their analysis concluded —assuming that current practices of load following operation and plans for routine repairs and anticipated replacements are maintained—the units are capable of providing service through the year 2035. Further and more recently, in May of 2011, Black and Veatch (as part of its Affirmation of Unit Life & Net Salvage Value Study) similarly concluded that Units ST2 and ST3 can continue operation to at least 2035, provided AEPCO maintains its standards of good operation, maintenance and safety practices and periodic replacement/refurbishment of plant equipment.

Apache Station Review

On October 1, 2009, AEPCO filed an application for a rate increase with the Arizona Corporation Commission ("Commission") [Docket No. E-01773A-09-0472]. To assist in processing the case, the Commission's Utilities Division Staff ("Staff") engaged Liberty Consulting Group ("Liberty") to provide testimony on cost of service, revenue requirements and rate sufficiency subjects, as well as to conduct a general prudence review. As part of Liberty's review findings, it provided conclusions and recommendations on eight areas—one of which was engineering analysis and plant operations.

In that area of engineering analysis/plant operations, Liberty concluded that:

> AEPCO's technical performance, personnel and facilities are generally sound and its management team is capable, knowledgeable and supported with appropriate tools. AEPCO's power plant operations are generally appropriate and typical of the industry, AEPCO's investment in new and upgraded facilities have been appropriate for the demand placed upon the Cooperative, and maintenance practices and spending appear to be consistent with the station's needs and good utility practice.[1]

However, Liberty did state one concern as follows:

[1] Direct Testimony (Prudence Review) of John Antonuk (Consultant) on Behalf of the Staff of the Utilities Division, Arizona Corporation Commission, dated July 30, 2010, page 10, lines 21-26.

> [D]espite reasonably effective performance historically, AEPCO faces significant questions about the future of its units. Apache Steam Units ST2 and ST3, the coal-fired units that currently produce more than 95 percent of the station's output, have operated in a base-load mode[2] for about 30 years, but now appear more likely to cycle. This change [in utilization] has resulted from a decline in the units' market competitiveness. Increased unit cycling may be having impacts on equipment, contributing to a significant drop in availability in 2009. Management needs to examine the potential for continuing lower station output, which if it continues, suggest a limited future for these units. The key question at this time is whether 2009 conditions are anomalous or a warning of continued deterioration.[3]

As a result of the 2009 market-driven changes in the operations of Units ST2 & ST3, Liberty recommended that: "AEPCO should conduct a study of the future role of Apache and how that role relates to member needs for future power supply."[4]

In the Rate Case Decision which concluded the case (Decision No. 72055) dated January 6, 2011, the Commission ordered AEPCO to file an Action Plan on Liberty's Prudence Review recommendations by February 1, 2011 and to file quarterly updates on each item of the Action Plan until all action items have been completed. The Commission also instructed AEPCO to include as part of its Apache Station study an assessment of the potential rate impacts associated with: "Environmental Protection Agency rulemakings regarding mercury emissions,

[2] AEPCO instead classifies ST2 and ST3 as "load following" units.
[3] *Ibid*, page 10, line 26 and page 11, lines 1-9.
[4] *Ibid*, page 13, lines 2-3.

coal ash, and any other known or pending EPA regulatory actions...and provide recommendations to the Commission regarding potential methods for mitigating...those rate impacts."[5]

AEPCO's Action Plan was filed with the Commission on January 27, 2011. Quarterly updates have been filed since that time. All but one of the tasks identified in the Action Plan have been completed. This report completes action on that remaining item—the Apache Role Study and EPA rate impact tasks of the Engineering Analysis/Plant Management sections which are identified at page 3 of the Action Plan.

Apache Station Operations Discussion

For many years prior to 2009, AEPCO operated Units ST2 and ST3 at high-capacity factors. However, in 2009, several factors came into play which resulted in those units operating at a lower capacity factor.

The first of these factors was a significant increase in the delivered coal costs for the units. Previous long-term AEPCO coal contracts had expired in 2008. The coal costs associated with the new contracts that became effective on January 1, 2009 were about 50% percent higher than the previous year's coal costs under the expired contracts.

As the Liberty analysis indicates, these higher coal costs greatly impacted the power costs and, therefore, the market competitiveness of Units ST2 and ST3. In turn, that caused the Salt River Project to reduce its scheduling of energy from those units for the two remaining years of

[5] Decision No. 72055, Finding 76.

its long-term, 100 MW power and energy sales agreement with AEPCO. Appendix 1 displays information concerning this combination of higher coal costs and the resulting SRP purchase power agreement "take" effects on the Units ST2 and ST3 capacity factors.

Second, as a result of the steep economic downturn which began in 2008, AEPCO's Class A Member Distribution Cooperatives ("Members") also required less power than previously had been the case from AEPCO's resources. Further, AEPCO's Partial-Requirements Members reduced their scheduled deliveries both (1) as a result of this market demand drop in their service territories, as well as (2) their ability to purchase against the units' lower cost energy from the market.

Finally, prices of natural gas dropped dramatically as a result of increased commodity supply, due primarily to new shale gas recovery technology. The decreased natural gas cost allowed natural gas-fired units to generate power more economically, which even further reduced the competitiveness of Units ST2 and ST3 energy. All of these factors combined in something like a "perfect storm" to impact substantially the units' historic high-capacity operating profile. They resulted in AEPCO's Units ST2 and ST3 generating at much lower capacity factors in 2009-2011 than historically had been the case.

However, AEPCO does not agree with Liberty's stated concern that this recent lower station output has had a detrimental impact on equipment which might limit the future use and productiveness of these units. For example, AEPCO has not seen any unusual deterioration in plant equipment during the major and minor overhauls which were conducted in the years 2010 and 2011.

Further, Black and Veatch (in its May 2011 Affirmation of Unit Life & Net Salvage Value Study) noted no unusual deterioration of plant equipment. Indeed, expressly to the contrary, it concluded that Units ST2 and ST3 can continue operation to <u>at least</u> 2035, provided AEPCO continues its standards of good operation, maintenance and safety practices and periodic replacement/refurbishment of plant equipment.

Also, as a part of this study and in order to assess the units' operational soundness and availability to similar units around the country, AEPCO compared Units ST2 and ST3 generating data to information available from the North American Electric Reliability Corporation ("NERC") Generating Availability Report, years 2006-2010, published in July 2011. Appendix 2 is a graphical representation of the five-year moving average Equivalent Availability Factors for AEPCO's Units ST2 and ST3 compared to the national average of Equivalent Availability Factors for similar coal primary fuel 100-199 MW units across the country.

As that graph indicates, AEPCO's Units ST2 and ST3 have operated and continue to operate, on average, consistently above a 90% availability factor as compared to the national average of only 85%. In fact, Apache Units ST2 and ST3 availability results have consistently ranged from seven to almost ten percentage points higher than national averages over the past several years, including 2010 and 2011. From all of this data, AEPCO has seen no indication of any concerns regarding unit deterioration. Therefore, we conclude that the problems encountered in 2009 were an anomaly—which we note was also suggested as a possible outcome of this study by Liberty.[6]

In regard to the future operation of Units ST2 and ST3, AEPCO has taken steps to moderate the high delivered coal costs of 2009 which impacted their market competitiveness. First, AEPCO filed a complaint several years ago concerning its high-priced rail tariffs with the Surface Transportation Board ("STB") and received a favorable ruling on that complaint at the end of 2011. In its decision, the STB prescribed rail rates for ten years from the date the complaint was filed. As a consequence, delivered coal costs will be reduced significantly for the remaining six years this prescription will be in effect. And, as a direct result of lower rail costs which provide access to competitive coal markets, AEPCO has negotiated a new set of coal contracts which have further reduced coal costs by almost 20% over previous years. Both of these factors are assisting in enhancing ST2 and ST3's market price competitiveness.

However, Units ST2 and ST3, of course, remain subject to competitiveness factors that are beyond AEPCO's control. AEPCO's Partial-Requirements Members have the contractual ability to schedule energy actually taken from these units down to very minimal levels. They will do so if market prices are lower than the cost of Units ST2 and ST3 power. Appendix 3 provides a graphical representation of recent market data (Palo Verde trading hub prices) and AEPCO RUS Form 12 data on economy purchased power costs and coal costs per MWH. Given that, AEPCO expects that Units ST2 and ST3 will, in all likelihood, continue to operate at lower

[6] Liberty Report, page 59: "Although it might be too soon to tell if 2009 was simply an unusual year for ST2 and ST3…"

capacity factors than those experienced prior to 2009. However, we do not see a limited future for these units as a result of operating at those lower capacity factors.

Impact of Known or Pending EPA Regulatory Actions

Attached as Exhibit A is information concerning the potential impacts of EPA rulemakings which could impact the Apache Station, AEPCO and its member-owners. Section 7 of Exhibit A also contains a discussion of why renewables are not an appropriate substitute for load following units such as Units ST2 and ST3 and estimated solar costs. This information was requested by Commissioner Newman at the August 22, 2012 IRP workshop.

Summary and Conclusions

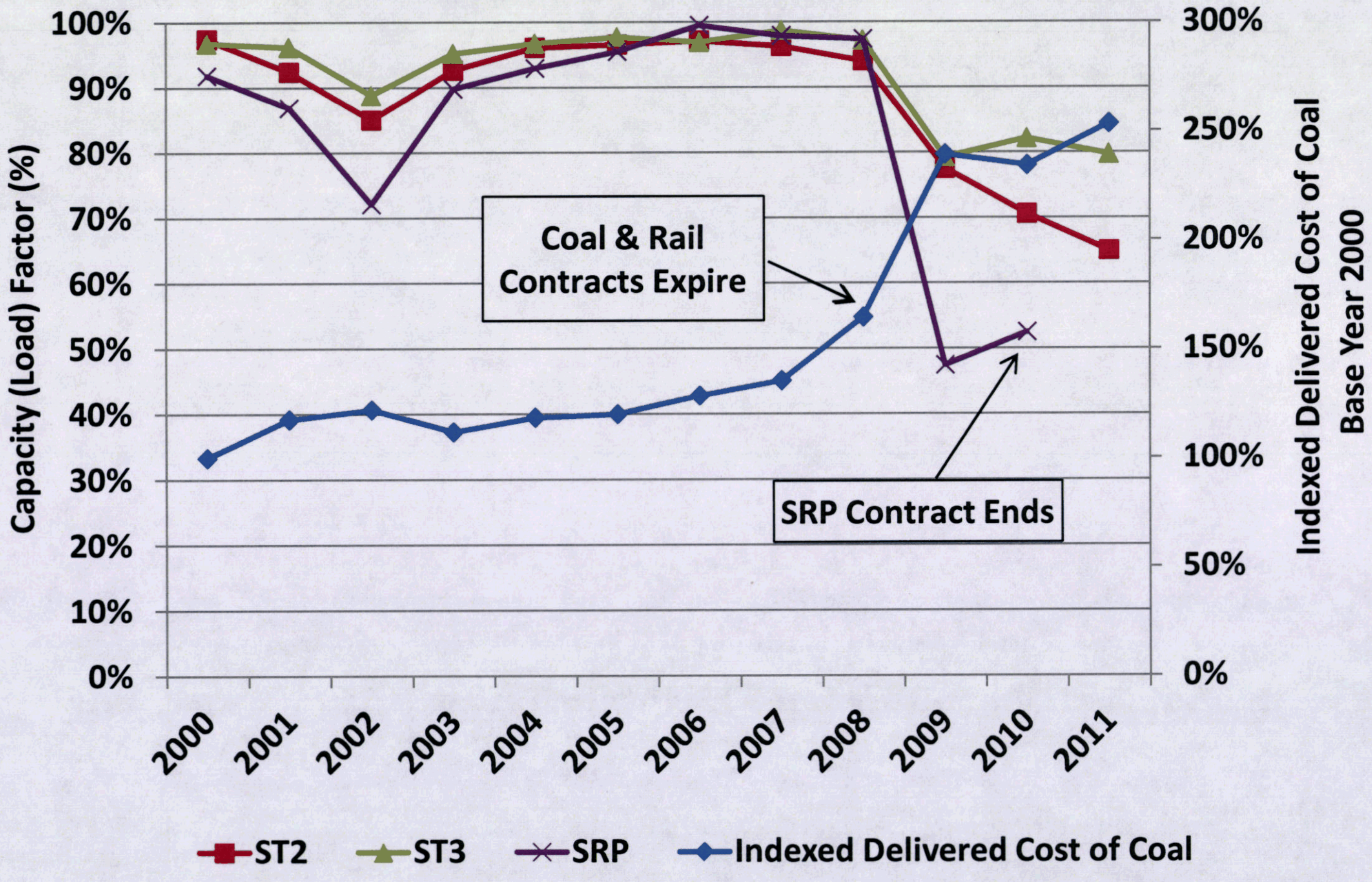
Units ST2 and ST3 are AEPCO's primary resources for meeting its contractual obligations to its Members. AEPCO has evaluated those units' operation during 2009-2011 and sees no indications that reduced station output has impacted the availability of these units or led to significant deterioration of plant equipment. Both Black & Veatch and AEPCO expect these units will continue to operate until at least 2035 in satisfying future Member requirements for power and energy.

APPENDIX 1

Arizona's G&T Cooperatives

Touchstone Energy® Cooperatives

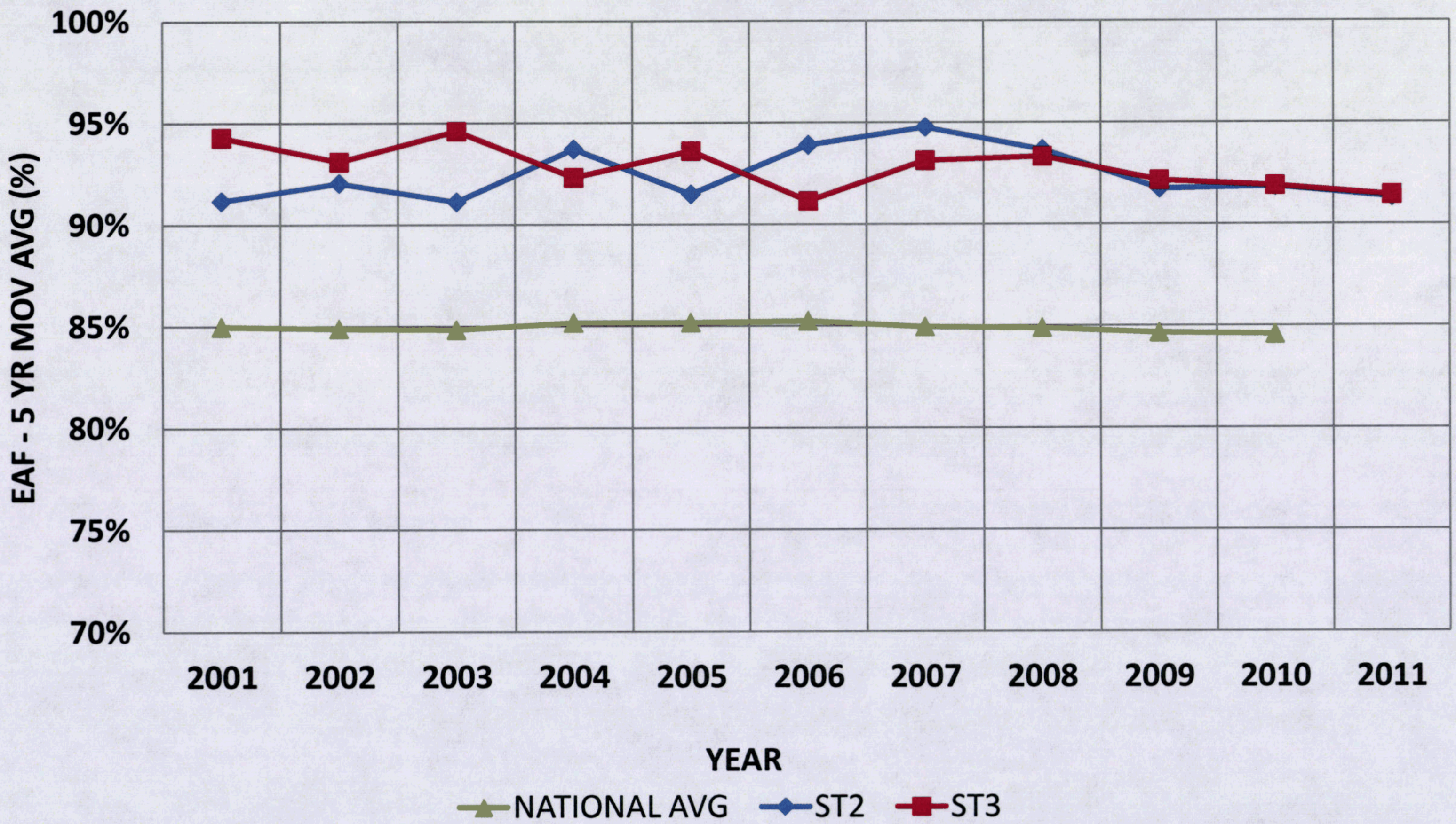
Available Capacity (Load) Factors vs Indexed Delivered Cost of Coal



APPENDIX 2

Arizona's G&T Cooperatives
Touchstone Energy® Cooperatives

EQUIVALENT AVAILABILITY FACTORS
APACHE STEAM 2 & 3 VS NATIONAL AVG
COAL PRIMARY FUEL 100-199 MW UNITS



APPENDIX 3

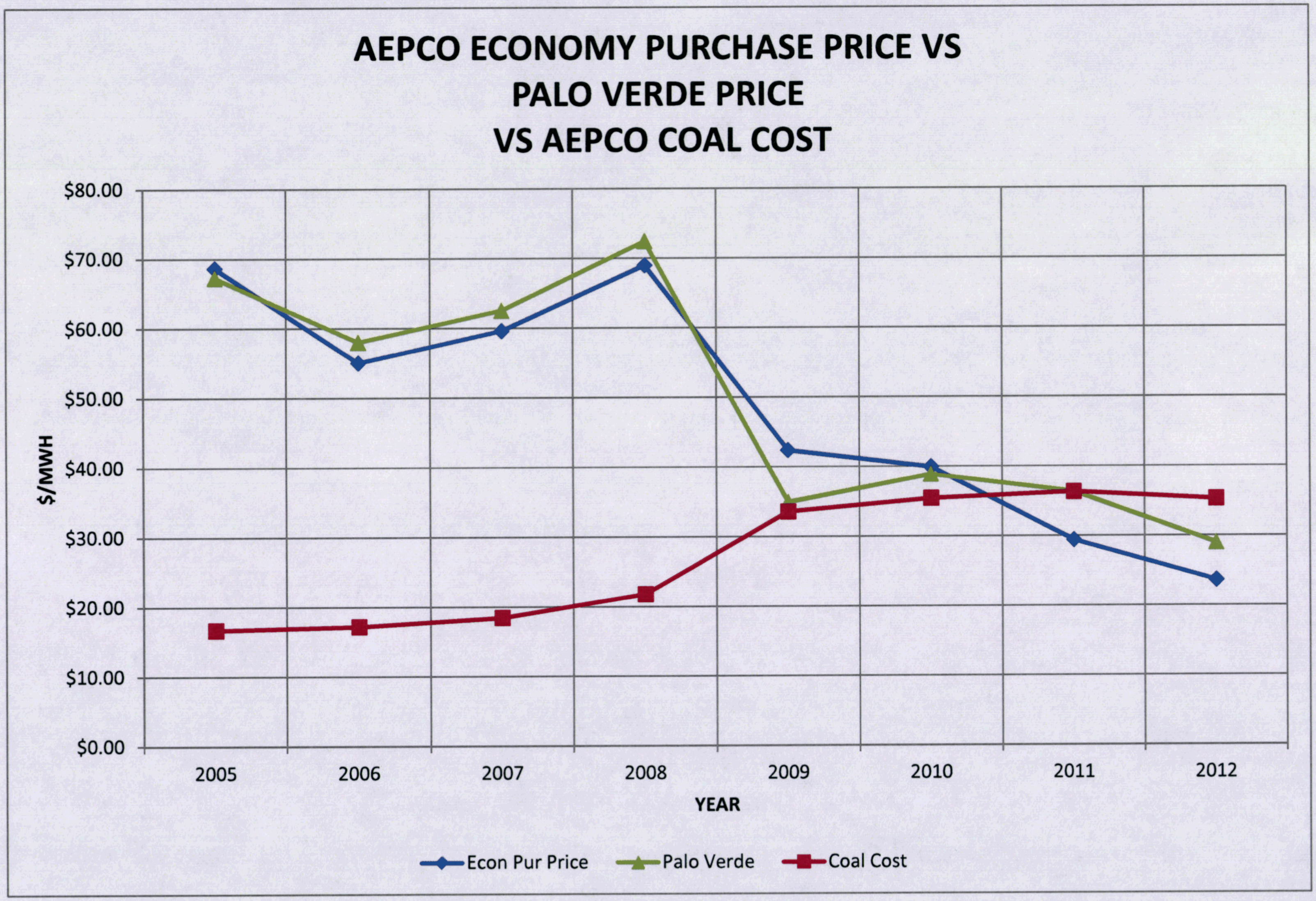

AEPCO ECONOMY PURCHASE PRICE VS
PALO VERDE PRICE
VS AEPCO COAL COST
$80.00
$70.00
$60.00
$50.00
$40.00
$30.00
$20.00
$10.00
$0.00
$/MWH
2005
2006
2007
2008
2009
2010
2011
2012
YEAR
Econ Pur Price
Palo Verde
Coal Cost

EXHIBIT A

EXHIBIT A

On January 6, 2011, at page 18 of Decision No. 72055, the Commission ("ACC") instructed AEPCO to include in its Apache Station Role Study additional information as follows:

> IT IS FURTHER ORDERED that Arizona Electric Power Cooperative, Inc. ("AEPCO") shall include in its study of the future of Apache Station an assessment of the potential rate impacts associated with looming Environmental Protection Agency rulemakings regarding mercury emissions, coal ash, and any other known or pending EPA regulatory actions that could impact the Station, AEPCO, and its customers and provide recommendations to the Commission regarding potential methods for mitigating the Cooperative and its customers' exposure to those rate impacts for the Commission's review and consideration.

This study provides information concerning that additional directive.[1]

1. Mercury Emissions, 40 C.F.R. 60 Subpart UUUUU

EPA's mercury emission rule is set forth in the "National Emission Standards for Hazardous Air Pollutants From Coal- and Oil-Fired Electric Utility Steam Generating Units and Standards of Performance for Fossil-Fuel-Fired Electric Utility, Industrial-Commercial-Institutional, and Small Industrial-Commercial-Institutional Steam Generating Units," promulgated on February 16, 2012. 77 Fed. Reg. 9304. This rule, known colloquially as the Mercury and Air Toxics Standard ("MATS"), establishes both an NSPS Standard under Clean Air Act Section 111 and a NESHAP under Clean Air Act Section 112.

i. Applicability

The MATS apply to any EGU with a generating capacity of more than 25 MW that serves a generator that produces electricity for sale.[2] The MATS are set based on existing commercially proven technologies that EPA believes are widely available and frequently used in the industry, such as electrostatic precipitators, fabric filters, flue gas desulfurization or dry sorbent injection.

---

[1] As part of this analysis, AEPCO provides data, where available, on the estimated cost impacts of and potential mitigation strategies concerning various EPA rulemakings and regulatory actions. Absent, however, definitive rules and/or final regulatory actions in relation to which precise engineering plans can be devised, it is not possible to formulate reliable rate impact projections.

[2] As of January 2012, Apache Generating Station ("Apache Station") has seven electric generation units: two coal/natural gas-fired steam electric units, a natural gas/fuel oil-fired steam electric combined-cycle unit, and four natural gas/oil-fired gas turbines. The rated generating capacity of the entire plant is approximately 604 MW. The plant supplies wholesale electric power to six rural electric distribution systems serving portions of Arizona, California and New Mexico. AEPCO also makes economy sales of electric power to other customers as market conditions permit.

This final rule does not regulate EGUs that combust natural gas exclusively or natural gas in combination with another fossil fuel where the natural gas constitutes 90.0 percent or more of the average annual heat input during any three consecutive calendar years or 85.0 percent or more of the annual heat input in one calendar year.[3] EPA considers such units to be natural gas-fired EGUs, notwithstanding the combustion of some coal or oil (or derivative thereof), and such units are not subject to this final rule.

The MATS set emission limits for the following HAPs: 1) Non-Mercury Metallic HAPs, 2) Acid Gas HAPs and 3) Mercury. Numerical emission limits are set based on sub-categorization of sources based on the design, utilization and/or location of the various types of boilers at different power plants. MATS identify two subcategories for coal-fired EGUs—EGUs designed for coal with a heating value greater than or equal to 8,300 Btu/lb and EGUs designed for low rank virgin coal; four subcategories of oil-fired EGUs—continental liquid oil-fired EGUs and limited-use liquid oil-fired EGUs; and a subcategory for units that combust gasified coal or solid oil—integrated gasification combined cycle ("IGCC") units.[4]

EGUs subject to the MATS that are under the same ownership, at the same plant site and in the same subcategory may demonstrate compliance by averaging their emissions. The final rule clarifies that facilities may use a longer averaging time for mercury, 90 days instead of 30 days, but, if used, the facility will have to meet a tighter standard of 1.0 lbs/TBtu.[5]

Affected Units at AEPCO:

- ST2, 195 MW – primarily coal-fired, also has gas and used oil – AFFECTED
- ST3, 195 MW – primarily coal-fired, also has gas and used oil – AFFECTED
- ST1, 75 MW – gas, fuel oil #2-#6, used oil or any combination – potentially AFFECTED
- CC#1 (ST1 + GT1) – gas, fuel oil – potentially AFFECTED (only in combined cycle)

Apache ST2 and ST3 will be subject to the MATS, because the rule applies to electric utility boilers that are over 25 MW. In addition to complying with the emissions limits, a tune-up of the burners and combustion controls will be required every 36 months under the rule.

ii. Emission Requirements

Table A lists the emission limits for coal-fired boilers set by the MATS. Table B lists the emissions limits for individual metals for coal-fired boilers set by the rule. Emission limits for coal-fired units are based on 30-day rolling averages, excluding periods of start-up and shut down where a work practice standard is imposed instead. EPA declined to set emission limits for organic HAPs or dioxins and furans and, instead, a work practice standard is included that would require an inspection of a boiler that is subject to the rule every 36 months. The records of emissions data must be kept on site at the facility for five years.

[3] 77 Fed. Reg. 9304 at 9309.
[4] *Id.* at 9367.
[5] *Id.* at 9385.

Table A. MATS Rule Emission Limits for Pulverized Coal-Fired Boilers

	Non-Mercury Metallic HAP[1]			Acid Gas HAP[2]		Mercury
Regulatory Option	Filterable PM	Total HAP Metals	Individual Metals	HCl Surrogate	SO_2 Surrogate	
Existing Units	0.030 lb/mmBtu 0.30 lb/MWh	0.000050 lb/mmBtu 0.00050 lb/MWh	<u>See</u> Table B	0.0020 lb/mmBtu 0.020 lb/MWh	0.20 lb/mmBtu 1.5 lb/MWh	1.20 lb/TBtu[3] 0.0130 lb/GWh[3] 4.0 lb/TBtu[4] 0.040 lb/GWh[4]
New Units	0.0070 lb/MWh	0.000060 lb/MWh	<u>See</u> Table B	0.40 lb/GWh	0.40 lb/MWh	0.00020 lb/GWh[3] 0.040 lb/GWh[4]

[1]Units may choose to comply with the limits for either filterable PM, total HAP metals or individual metals.
[2]Units that use a FGD system and SO_2 CEMS may choose to comply with the SO_2 limit as an alternative to the HCl limit. All other units must comply with the HCl limit.
[3]For units designed to burn coals other than lignite.
[4]For units designed to burn lignite.

Table B. MATS Rule Individual Metal Emission Limits for Pulverized Coal-Fired Boilers

	Existing Units		New Units
HAP Metal	lb/TBtu	lb/GWh	lb/GWh
Antimony	0.80	0.0080	0.0080
Arsenic	1.1	0.020	0.0030
Beryllium	0.20	0.0020	0.00060
Cadmium	0.30	0.0030	0.00040
Chromium	2.8	0.030	0.0070
Cobalt	0.80	0.0080	0.0020
Lead	1.2	0.020	0.0020
Manganese	4.0	0.050	0.0040
Nickel	3.5	0.040	0.040
Selenium	5.0	0.060	0.0060

iii. Annual Compliance Demonstration Requirements

Compliance with each applicable emission limit must be demonstrated during an initial performance test and continuous monitoring. The initial performance test may be a 30-day period of operation of continuous emissions monitoring systems ("CEMS") or it may be a stack test based on three test runs using the stipulated EPA Test Methods. Emission limits for which compliance demonstration may be demonstrated by an initial performance test using CEMS include those for SO_2, HCl or PM using a continuous parametric monitoring system ("PM CPMS"). For demonstration of compliance with the emission limitations for mercury, only continuous monitoring using an Hg CEMS or a sorbent trap monitoring system is allowed.

If initial compliance with the emission limitations for filterable PM, total HAP Metals or individual HAP metals is demonstrated via stack testing, then ongoing compliance demonstration must be performed using either a PM CPMS or by repeating the compliance stack testing on a quarterly basis. If the PM CPMS option is selected, then operating limits set during the performance test are used to determine ongoing compliance, as described in the next section. The MATS also establish a work practice standard requiring a tune-up of the burner and combustion controls on a regular basis. The completion of the initial tune-up is required as part of the initial compliance demonstration.[6]

iv. Continuous Compliance Demonstration Requirements

Following the initial compliance demonstration as discussed above, a facility subject to the MATS must continue to demonstrate continuous compliance. The emission limits set by the MATS are 30-day rolling averages, excluding periods of start-up and shut down; work practice standards included in the rule effectively limit emissions during periods of start-up and shut down. The work practice standards require the use of "clean fuels" (natural gas or distillate oil) for ignition during start-up, and dictate the use of all installed air pollution control technologies, within practical limits, during periods of start-up and shut down when coal is being fired. The work practice standard requiring a tune-up of the burner and combustion controls requires that continuous compliance be demonstrated by repeating the tune-up every 36 months. This frequency may be reduced to every 48 months if neural network combustion optimization software is used.[7]

[6] *Id.*
[7] *Id.*

When the initial compliance demonstration is made using CEMS (including Hg CEMS or sorbent trap monitoring system), continued CEMS monitoring is required to demonstrate continuous compliance. If stack testing is used to demonstrate initial compliance, then those stack tests must be repeated on a quarterly basis to continue to demonstrate continuous compliance.[8]

v. Cost-Benefit Analysis

EPA projects that the annual incremental compliance cost of MATS is $9.6 billion in 2015.[9] The agency estimated that there were approximately 1,400 units affected by MATS, approximately 1,100 existing coal-fired units and 300 oil-fired units at about 600 power plants. The annualized incremental cost is the projected additional cost of complying with the rule in the year analyzed and includes the amortized cost of capital investment and the ongoing costs of operating additional pollution controls, needed new capacity, shifts between or amongst various fuels and other actions associated with compliance. The total incremental compliance cost includes compliance costs modeled in the Integrated Planning Model ("IPM")[10] of $9.4 billion; costs modeled outside of the IPM for oil-fired EGUs of $56 million; and monitoring, reporting and recordkeeping costs of $158 million.[11] Additionally, EPA modeling indicates MATS will result in an increase of the average retail price of electricity by approximately three percent, primarily due to increased demand for natural gas.[12]

vi. Analysis

Apache Station will be subject to MATS, as it has a generating capacity of approximately 604 MW and supplies wholesale electric power. While MATS will place a substantial financial burden on the industry, the impact on Apache Station will be somewhat reduced, because AEPCO already monitors for NOx and SO_2 on ST2 and ST3, NOx on ST1 and CC1, and Hg voluntarily through a State rule with ADEQ.

In addition to monitoring criteria air pollutants PM, PM_{10}, SO_2, NOx, CO, VOC and Pb, AEPCO currently voluntarily monitors for numerous non-criteria regulated air pollutants, including mercury. In July 2010, Apache Station installed and began operating a mercury emissions control system on ST2 and ST3. In 2011, Apache Station reported levels

[8] An exception applies where initial compliance with the emission limitations for filterable PM, Total HAP Metals or individual HAP metals is demonstrated via stack testing and the owner elects to use a PM CPMS to verify continuous compliance. In that case, a site-specific operating limit will be established during the initial performance test based on data produced by the PM CPMS during that test. That operating limit must be maintained, on a 30-day rolling average basis, at or below the highest one-hour average value measured during the performance test. The operating limit will be reset during each subsequent annual performance test.

[9] 77 Fed. Reg. 9304 at 9413.

[10] Developed by ICF Consulting, Inc. and utilized by EPA, IPM is a multi-regional, dynamic, deterministic linear programming model of the U.S. electric power sector. It provides forecasts of least-cost capacity expansion, electricity dispatch and emission control strategies for meeting energy demand and environmental, transmission, dispatch and reliability constraints.

[11] *Id.* at 9425.

[12] *Id.* at 9414.

of 1.20E-06 (lb/MMbtw), 0.000437 (lbs/hr) and 1.37E-03 (tons/yr).[13] MATS mercury emission level requirements are more stringent than Apache Station's current emissions; therefore, Apache Station will still require additional improvements to meet the new standards. Activated Carbon Injection (ACI) is a method of air pollution control that should be able to achieve the additional mercury reductions. It is, however, extremely expensive. AEPCO is evaluating other options, such as fine tuning its existing system, to see if the final mercury reductions can be achieved at less cost.

2. Hazardous and Solid Waste Management System; Identification and Listing of Special Wastes; Disposal of Coal Combustion Residuals From Electric Utilities

Coal Combustion Residuals ("CCRs"), or coal ash, are currently considered exempt wastes under the Resource Conservation and Recovery Act ("RCRA"). On June 10, 2010, EPA proposed to regulate coal ash for the first time to address the risks from the disposal of the wastes generated by electric utilities and independent power producers. In relation to the proposed rule, EPA is considering two possible options for the management of coal ash under RCRA. Under the first proposal, EPA would reverse its Bevill Regulatory Determinations regarding CCRs and list these residuals as special wastes subject to the hazardous waste regulations under Subtitle C of RCRA, when destined for disposal in landfills or surface impoundments.[14] Under the second proposal, EPA would leave the Bevill determinations in place and regulate coal ash under Subtitle D of RCRA, the section for non-hazardous wastes.[15] The agency has not yet issued a final rule. The last agency action involving this rule was the closing of the Notice of Data Availability comment period on November 14, 2011.

In the proposed rule, EPA stated it will not revise its 2000 determination of beneficial reuse relevant to coal ash because of the benefits of beneficial reuse of CCR to both the environment and the economy.[16] The proposed rule would not regulate CCR destined for use in new products such as cement, concrete, brick, wallboard and roofing materials. EPA did propose some changes to aspects of beneficial reuse determinations. Certain use of large volumes of CCR in sand and gravel pits for restructuring landscape would no longer be considered beneficial reuse.

i. Subtitle C Option

Under the Subtitle C option, there would be a federal requirement for permit issuance by individual states. Permits would be enforced at the state and federal level with corrective action monitored by authorized states and the EPA. The effective dates of the permit would vary, as each state would be required to adopt the rule individually; this process could take one to two years or more to complete. This option would contain financial assurance and requirements for

---

[13] Class I Air Permit Quality Permit Renewal Application, Dec. 2011.
[14] Disposal of Coal Combustion Residuals from Electric Utilities, 75 Fed. Reg. 35128, 35128 (proposed Jun. 10, 2010).
[15] *Id.*
[16] *Id.*

storage, including containers, tanks and containment buildings. Surface impoundments[17] built before the rule is finalized would be required to remove solids and meet land disposal restrictions and retrofit with a liner within five years of the effective date of the rule; Subtitle C would effectively phase out use of existing surface impoundments. Surface impoundments built after the rule is finalized must meet land disposal restrictions and liner requirements, effectively phasing out the use of new surface impoundments.

Subtitle C would also impose new restrictions for landfills built before and after the promulgation of the final rule. If AEPCO chooses to dispose of CCRs on-site, a hazardous waste landfill meeting all the disposal restrictions and liner requirements would have to be permitted and built. If AEPCO ships CCRs offsite, the new landfill requirements[18] would likely increase costs associated with the removal of CCRs to an offsite location.

ii. Subtitle D Option

Under the Subtitle D option, EPA would develop national minimum standards for landfills and surface impoundments where CCR from electric utilities and independent power producers are disposed. These standards would be based on EPA-developed standards for municipal solid waste landfills and would include restrictions on location, design, operation, groundwater monitoring, closure and post-closure care. The final rule promulgated by EPA would be enforced through citizen suits (states could act as citizens) and self-implementing for corrective action. EPA is considering a subsequent rule using the Comprehensive Environmental Response, Compensation, and Liability Act ("CERCLA") 108(b) authority for financial assurance.[19]

The final rule would become effective six months after it is promulgated, but certain provisions would have a longer effective date. Surface impoundments built before the rule is finalized would be required to remove solids and retrofit impoundments with a composite liner or cease receiving CCRs within five years of its effective date and close the unit. Surface impoundments built after the rule is finalized must install composite liners, but there would be no land disposal restrictions. The Subtitle D proposal would additionally impose controls for facility surface run-off, pollution caused by fugitive dust, recordkeeping and discharges to surface waters and would require a monitoring well system to be installed at all (new *and* existing) CCR landfills and surface impoundments.[20] Because EPA cannot impose treatment

---

[17] CCR Surface Impoundment or impoundment means a facility or part of a facility which is a natural topographic depression, man-made excavation or diked area formed primarily of earthen materials (although it may be lined with man-made materials) which is designed to hold an accumulation of CCRs containing free liquids, and which is not an injection well. Examples of CCR surface impoundments are holding, storage, settling and aeration pits, ponds and lagoons. CCR surface impoundments are used to receive CCRs that have been sluiced (flushed or mixed with water to facilitate movement) or wastes from wet air pollution control devices, often in addition to other solid wastes.

[18] Effects on existing landfills include: Expansions of current cells or construction of new cells composite liner/leachate collection system, groundwater monitoring system within one year, run-on/run-off controls within two years, control fugitive dust (< 35 µg/m3), closure and post-closure plans, obtain RCRA permit (18-24 months).

[19] 75 Fed. Reg. 35128 at 35133.

[20] *Id.*

requirements under Subtitle D that would effectively phase out the wet handling of CCR as it has proposed to do under Subtitle C, wet handling of CCR could continue under Subtitle D as long as existing surface impoundments are retrofitted to meet proposed design standards.

Subtitle D would also impose new restrictions for landfills built before and after the promulgation of the final rule. While AEPCO likely does not qualify under landfill requirements, if AEPCO ships CCRs offsite, the new landfill requirements[21] would likely increase costs associated with the removal of CCRs to an offsite location. However, the landfill requirements under Subtitle D are less severe than Subtitle C and, therefore, would most likely not increase CCR removal costs for AEPCO as severely.

a. Subtitle C and D Comparison

General Provisions	**Subtitle C**	**Subtitle D**
Effective Date	Timing dependent on state permitting process; expected to take 1-2 years or more	Generally six months after final rule is promulgated (longer effective date for certain provisions)
Enforcement	State and federal	Citizen suits
Corrective Action	Monitored by authorized states and EPA	Self-implementing
Financial Assurance	Yes	Considering subsequent rule using CERCLA 108(b)
Permit	Federal requirement for state permit issuance	No
Requirements for Storage, including containers, tanks and containment buildings	Yes	No

[21] Effects on existing landfills include: Continue operations on current liners, unstable area demonstrations and close within five to seven years if unsuccessful, groundwater monitoring system within one year, run-on/run-off controls, control fugitive dust (< 35 µg/m3), closure and post-closure plans, financial assurance.

Existing Surface Impoundment Requirements[22]	**Subtitle C**	**Subtitle D**
Liner	Excavate CCR and retrofit with double liner/leachate collection system within 5 years OR close within 2 years of final receipt of CCR	Excavate CCR and retrofit with composite liner/leachate collection system within 5 years OR close
Unstable area demonstration	No	Yes; Close within 5-7 years if unsuccessful
Monitoring	Groundwater monitoring system within 1 year	Groundwater monitoring system within 1 year
Controls	Run-on/run-off controls within 2 years	Run-on/run-off controls
Control fugitive dust (< 35 μg/m3)	Yes	Yes
Prevent Discharges	Yes	Yes
Inspection requirements	Yes	Yes
Closure and post-closure plans	Yes	Yes
Misc.	N/A	Additional Option D—no retrofit

iii. Cost-Benefit Analysis

The Regulatory Impact Analysis estimates the average annual regulatory cost for the next 50 years to be $1.474 billion a year under the Subtitle C option and $587 million a year under the Subtitle D option.[23] These estimates include the costs of industry compliance and state and federal government oversight and enforcement costs. The major difference in the cost estimates for the two options is largely the result of compliance rates and the retrofit requirement for Subtitle C; the analysis assumes a 48 percent compliance rate under Subtitle D (where EPA has no enforcement authority) versus a 100 percent compliance rate under Subtitle C.

iv. Analysis

AEPCO's Apache Station facility will be subject to coal ash disposal regulations when finalized. Since 1995, Apache Station has had seven lined impoundments onsite. The financial burden on AEPCO depends on whether Subtitle C or Subtitle D is promulgated.

Subtitle C will place a much higher financial burden on AEPCO. While Apache Station's impoundments are already retrofitted with liners, Subtitle C requires double liners. Subtitle C would also require AEPCO to install and/or implement a groundwater monitoring

[22] 75 Fed. Reg. 35128 at 35133.
[23] *Id.* at 35134.

system within a year, run-on/run-off controls, control of fugitive dust (< 35 μg/m3), prevention of discharges, inspection requirements and closure and post-closure plans. Additionally, AEPCO would be required to obtain a permit under RCRA, adding additional substantial expense.

Subtitle D would still place a significant financial burden on AEPCO, although less than Subtitle C. While Apache Station's impoundments are already lined, they do not meet the current proposed design standards. AEPCO would be required to retrofit the impoundments with additional liners. Subtitle D would also require AEPCO to install and/or implement a groundwater monitoring system within a year, run-on/run-off controls, control of fugitive dust (< 35 μg/m3), prevention of discharges, inspection requirements and closure and post-closure plans.

The issue of regulating CCRs has been a highly divisive issue in Congress. This issue was attached to the omnibus transportation bill in the 2012 session, but the amendment was deleted from the bill prior to passage. Presently, it is unclear the direction EPA and Congress intend to move and the EPA has not issued a timeframe for the release of the final rule.

3. <u>Boiler MACT Rule, 40 C.F.R. 63 Subpart DDDDD</u>

The EPA developed a MACT for boilers and process heaters as part of a NESHAP under Section 112 of the CAA. EPA first promulgated a final rule for new and existing industrial/commercial/institutional boilers and process heaters on September 13, 2004. However, on June 19, 2007, the United States Court of Appeals for the District of Columbia Circuit vacated the 2004 standards prior to the compliance deadlines. EPA proposed another rule in June of 2010, but requested the court delay its promulgation. However, the court denied the request.

In response, on February 21, 2011, EPA finalized the current rule on February 21, 2011 and published this regulation on May 20, 2011 (76 FR 15608; 40 C.F.R. 63 Subpart DDDDD). Due to increasing industry concerns, on December 23, 2011, EPA proposed amendments to the current NESHAP for area source boilers and then proceeded to issue a No Action Assurance Letter on March 13, 2012, stating that EPA will not pursue enforcement action for violations of the initial tune-up deadlines; the current No Action Assurance Letter will continue until either the final reconsideration rule is issued and becomes effective or until December 31, 2012. The EPA has stated that it intends to issue the final reconsideration rule prior to any of the compliance dates for existing sources.

Based on public comments and additional data provided after the current NESHAP rules were finalized, EPA has proposed some significant changes to the required air toxics standards for boilers and incinerators. The proposed amendments to NESHAP for major source boilers would create new subcategories for light and heavy industrial liquids to reflect design difference in boilers, set new emissions limits for PM that are different for each solid fuel subcategory, set new emissions limits for carbon monoxide, allow alternative total selective metals emission limits to regulate metallic air toxics instead of using PM as a surrogate, replace numeric dioxin emissions limits with work practice standards, increase flexibility in compliance monitoring to remove CEMs requirements for particle pollution for biomass units and to propose carbon monoxide limits that are based on either stack testing or continuous monitoring, revise emissions limits for units located outside the continental United States and allow units burning clean gases to qualify for work practice standards instead of numeric emissions limits.[24]

i. Boiler MACT Applicability

The Boiler MACT rule addresses the combustion of non-solid waste materials in boilers and process heaters located at major sources of HAPs and applies to any industry using a boiler[25] or process heater. A boiler is defined as an enclosed device using controlled flame combustion and having the primary purpose of recovering thermal energy in the form of steam or hot water. EPA identified fifteen different subcategories of boilers and process heaters based on the design of the units; the rule contains specific requirements for each subcategory. In certain instances, there are boilers and process heaters that are already regulated under other MACT standards, such as MATS; in such cases, the boilers and process heaters that are already subject to another MACT standard are not subject to the boiler standards.[26]

Affected Units at AEPCO:

- ST1, 75 MW, Gas: 965 MMBtu/hr

ii. Emission Requirements

The Boiler MACT establishes numeric emission limits for Hg, dioxin/furan, PM, HCl and CO for existing and new boilers and process heaters located at major sources. Additionally, the Boiler MACT requires monitoring to assure compliance with emission limits. The largest major source boilers must continuously monitor their particle emissions as a surrogate for metals such as lead and chromium. All units larger than 10 MMBtu/hr must monitor oxygen as a measure of good combustion.

For all new and existing natural gas and refinery gas-fired units, the final rule establishes a work practice standard, instead of numeric emission limits. Units combusting other gases can qualify for work practice standards by demonstrating that they burn "clean fuel," with contaminant levels similar to natural gas.

iii. Compliance and Record Keeping

Boiler MACT requires compliance demonstration of all applicable emission limits using performance testing, fuel analysis or continuous monitoring systems ("CMS"), including a CEMS or continuous opacity monitoring system, where applicable.[27] Existing boilers or process

---

[24] EPA Overview Fact Sheet: *EPA's Air Toxics Standards Major and Area Source Boilers and Certain Incinerators Overview of Changes and Impact.*
[25] Boilers include: Industrial boilers, institutional boilers and commercial boilers.
[26] 40 C.F.R. § 63.7491.
[27] 40 C.F.R. § 63.7505.

heaters in the same subcategory at the same facility may demonstrate emission limit compliance for PM, HCl or HG by averaging, if the averaged emissions are not more than 90 percent of the applicable emission limit. New boilers or process heaters may not be included in an emissions average.[28]

Existing major source facilities are required to conduct a one-time energy assessment to identify cost-effective energy conservation measures. For all new and existing natural gas- and refinery gas-fired units, the operator will be required to perform an annual tune-up for each unit. All new and existing "limited use" boiler operators will be required to perform a tune-up for each unit once every two years.

Existing affected sources must demonstrate initial compliance no later than 180 days after the compliance date[29] of March 21, 2014[30]; however, this date is currently stayed. All applicable performance tests, as specified in § 63.7520, must be completed on an annual basis, except those for dioxin/furan emissions. Annual performance tests must be completed no more than 13 months after the previous performance test. Annual performance testing for dioxin/furan emissions is not required after the initial compliance demonstration.[31] Facilities must keep records of notifications, compliance demonstrations, performance evaluations, progress reports, CMS record keeping and maintenance.

iv. Cost-Benefit Analysis

EPA estimated that there are approximately 13,840 boilers and process heaters at major sources in the United States and that approximately 47 new units would be installed between 2011 and 2014. The Agency projects that the annual installation and maintenance compliance cost of Boiler MACT is $1.4 billion per year beginning in 2014. The estimated social cost of the major source rule is just under $1.5 billion. EPA's economic model suggests that industries are able to pass approximately $500 million of the rule's costs to consumers (e.g., higher market prices).[32] The Agency's analysis broke down the capital and annualized costs for existing major sources as follows: solid units: $2.182 billion/$873 million, liquid units: $2.656 billion/$833 million, non-continental liquid units: $86 million/$24 million, gas 1 units: $70 million/$31 million, gas 1 metallurgical furnaces: $4.5 million/$2 million, gas (other) units: $79 million/$39 million, and limited use units: $3.1 million/$1.3 million.[33]

v. Analysis

Apache Station's ST1 unit will most likely be subject to the rule as the unit is not regulated under MATS when burning at least 90 percent natural gas per year (or 85 percent

[28] 40 C.F.R. § 63.7522.
[29] 40 C.F.R. § 63.7510.
[30] 40 C.F.R. § 63.7495.
[31] 40 C.F.R. § 63.7515.
[32] EPA Regulatory Impact Analysis: *National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters*, 1-1 (Feb. 2011).
[33] *Id.* at 3-3.

natural gas over three years). ST1 qualifies under subcategory (l)[34] (units designed to burn natural gas, refinery gas or other gas 1 fuels), as it burns only natural gas at 965 MMBtu/hr; therefore, ST1 will only be subject to work practice standards and not specific emission limitations. AEPCO will also be required to conduct a one-time energy assessment on ST1 to identify cost-effective energy conservation measures, as well as an annual tune-up on the unit. Other units at Apache Station that are already covered under another MACT standard are not subject to Boiler MACT.

Due to ST1's qualification as a natural gas unit, it will only be subject to work practice standards and not specific emissions standards. In addition to AEPCO's emissions monitoring of ST1, AEPCO will have to bear the cost of the one-time energy assessment and annual tune-ups on the unit.

The issue of regulating boilers and process heaters has received substantial judicial attention and industry opposition. Presently, it is unclear when the EPA plans to move forward with the final amendments to the current rule; additionally, the EPA is already past its declared April 2012 time frame for promulgation of a final rule. Currently, Boiler MACT requirements remain stayed.

4. <u>Reciprocating Internal Combustion Engines</u>

NESHAPs for Stationary Reciprocating Internal Combustion Engines ("RICE"), 40 C.F.R. Subpart ZZZZ,[35] applies to existing diesel generators at the Apache Station. Subpart ZZZZ was initially promulgated on June 15, 2004, 69 Fed. Reg. 33506, and has been amended numerous times since its initial promulgation date.

i. Applicability

This rule applies to diesel generators used at the facility as (1) start-up engines for Gas Turbines Numbers 1 and 4 and (2) an emergency generator in the event of a facility power interruption. These diesel generators must comply with the regulation no later than May 3, 2013.

Affected Units at AEPCO:

- GT1 Start-Up Diesel Engine – diesel (fuel oil #2)
- GT4 Start-Up Diesel Engine – diesel (fuel oil #2)
- Emergency Diesel Engine – diesel (fuel oil #2)

---

[34] 40 C.F.R. § 63.7499.
[35] 40 C.F.R. § 63.6580, *et. seq.*

ii. Emission Requirements

While this rule establishes emissions limitations for many categories of RICE,[36] the 430 HP start-up engines (defined by this rule as "black-start" engines) and less than 500-HP emergency generator at the Apache Station are not subject to emissions limitations.[37] They must, however, meet various maintenance and operational requirements established by the NESHAP.

iii. Compliance and Record Keeping

Engines must be operated according to manufacturer's emission-related written instructions; if these are unavailable, a facility must develop its own maintenance plan which must provide, to the extent practicable, for the maintenance and operation of the engine in a manner consistent with good air pollution control practice for minimizing emissions.[38] Records of all required maintenance must be maintained.[39]

Apache Station must install a non-resettable hour meter on its emergency generator to demonstrate that it meets the non-emergency hour limitations for this engine.[40] Records may be required to document the number of hours spent for emergency operation, including what classified the operation as an "emergency" and how many hours are spent for non-emergency operation, depending on whether the emergency engine meets non-emergency engine "comparable" standards.[41]

iv. Cost-Benefit Analysis

EPA estimates that complying with the RICE rule will have an annualized cost of approximately $345 million per year (2007 dollars).[42] Using these costs, EPA estimates in its economic impact analysis that the NESHAP will have limited impacts on the eight industries affected (electric power generation is one of the affected industries) and their consumers.

EPA estimates the monetized benefits of this NESHAP to be $930 million to $2.0 billion (2007 dollars) in the year of full implementation. EPA believes that the benefits are likely to exceed the annualized costs of $345 million by a substantial margin under this rulemaking even when taking into account uncertainties in the cost and benefit estimates.

---

[36] Regulation is largely dependent on type of engine, size of engine and category of facility (major or area source of HAPs).
[37] 40 C.F.R. § 63.6602; Table 2c to Subpart ZZZZ of Part 63.
[38] 40 C.F.R. § 63.6625(e).
[39] 40 C.F.R. § 63.6655(a)(4).
[40] 40 C.F.R. § 63.6625(f).
[41] 40 C.F.R. § 63.6655(f)(1).
[42] Regulatory Impact Analysis (RIA) for Existing Stationary Reciprocating Internal Combustion Engines (RICE) NESHAP, Final Report (February 2009).

v. Analysis

AEPCO's Apache Station GT1 and GT4 start-up generators and emergency generator are subject to the RICE NESHAP. Costs of compliance should be minimal for these existing, diesel-fired engines, as the black-start engines and emergency engine are not subject to emission limitations and only work-practice standards are required.

5. Approval, Disapproval and Promulgation of Air Quality Implementation Plans: Arizona; Regional Haze State and Federal Implementation Plans, 77 Fed. Reg. 42834 (July 20, 2012)

EPA is proposing a partial approval and partial disapproval of the Arizona Regional Haze State Implementation Plan (AZ RH SIP) and proposed promulgation of a Federal Implementation Plan to impose EPA's preferred best available retrofit technology (BART) (the EPA BART FIP) set forth in the July 20, 2012 *Federal Register*. AEPCO does not believe that disapproval of the AZ RH SIP is appropriate and believes that promulgation of the proposed EPA BART FIP at this time is inconsistent with the Clean Air Act and with the BART requirements set forth in the *Code of Federal Regulations*.

EPA bases its BART determination on evidence suggesting that "SCR is commonly installed as an add-on post combustion control," and that "existing vendor literature and technical studies indicate that SCR systems are capable of achieving a 0.05 lb/mmBtu emission rate." 77 Fed. Reg. at 42853. EPA's presumption that SCR can achieve a 30-day average, 0.05 lb/mmBtu NOx rate fails to take into consideration the operational realities of electric utilities. ST2 and ST3 do not operate under steady-state conditions, but are load following units and are anticipated to see increased cycling due to changes in AEPCO's members' requirements. Low-load cycling, start-up and shut down are typical operating conditions for load following units. AEPCO must have the flexibility to cycle between units and the reality is that 0.05 lb/mmBtu NOx cannot be achieved during low-load cycles. Based on RBLC data, even *new* coal-fired electric generating units with SCR are only required to achieve 0.05 lb/mmBtu averaged *over 12-months*. There is no way that a retrofit coal-fired unit can achieve this limit over 30 days, despite what vendors represent.

i. Applicability

Affected Units at AEPCO:

- ST2, 195 MW
- ST3, 195 MW
- ST1, 75 MW

AEPCO agrees with the proposed approval for PM and SO_2 BART emission limits and controls.

ii. Cost-Benefit Analysis

AEPCO is concerned that EPA has substantially underestimated the cost of installing SCR at AEPCO's Apache Generating Station by substituting the site-specific data that AEPCO, its contractors and ADEQ used in the SIP process for the "one size fits all" IPM Model, which was developed for the Eastern United States, where there is greater transmission capacity, less distance and greater availability generally of engineering, construction and technical support.

EPA has estimated the total project cost at $33,279,000 per unit, without allowing any owners' costs or "AFUDC" (allowance for funds during construction). Whatever may be the merits of this approach for comparability purposes, it is not appropriate for AEPCO. AEPCO has very limited working capital and, as a result, must borrow, in the form of bridge financing, the working capital necessary to install the proposed SCR control. This "interest during construction" or IDC is a legitimate cost that AEPCO must pay to outside third parties and must be incurred by AEPCO's members in their rates. AEPCO, thus, does not believe that EPA may disallow this cost. Similarly, AEPCO does not believe that "good air pollution engineering practice" allows construction without contingency allotments, taxes and similar necessary expenses.

EPA's estimated combined per unit cost is $33,279,000 versus AEPCO's estimate of $85,666,000. Doubling these (to account for the fact that both Unit ST2 and ST3 must be addressed) results in a total cost of approximately $66.5 million for EPA and $171.3 million for AEPCO before operating costs. EPA should reevaluate its estimate in light of AEPCO's site-specific analysis.

AEPCO's estimated installed cost of SCR based on site-specific information is more than double that of EPA's. Adding this cost to EPA's estimate for LNB and OFA will result in an annualized cost of $3,508 per ton, which is 1.2 to 1.5 times EPA's estimates. On a maximum deciview ("dv") improvement basis, AEPCO's estimate will result in a cost of $13.9 million per dv, which is 1.7 times the EPA estimate. Overall, the cost burden to AEPCO for SCR is disproportional to the benefit with respect to the potential deciview improvement.

iii. Analysis

AEPCO's rural electric cooperative status has several important implications for AEPCO's ability to afford the installation of controls such as the proposed SCR. AEPCO operates only a single station, the Apache Generating Station, and has only approximately 147,000 meters in the service population of its Class A members. The situation is further exacerbated by the fact that almost all of the effective power at the Apache Station (475 MW out of just over 600 MW capacity) are subject to BART requirements. As a result, AEPCO has little or no ability to "spread costs" over unaffected units, other facilities or a large system of units and ratepayers. Instead, the entire cost would be borne by a relatively small number of AEPCO Class A members and their members. AEPCO estimates an 18 percent rate impact at wholesale in relation to the proposed SCR.

6. Additional Regulations

i. National Pollutant Discharge Elimination System—Cooling Water Intake Structures at Existing Facilities and Phase I Facilities, 76 FR 22174

EPA proposed NPDES—Cooling Water Intake Structures at Existing Facilities and Phase I Facilities, 76 FR 22174, on April 20, 2012. This proposed rule would establish requirements under Section 316(b) of the Clean Water Act for all existing power generating facilities and existing manufacturing and industrial facilities that withdraw more than two million gallons per day of water from waters of the U.S. and use at least 25 percent of the water they withdraw exclusively for cooling purposes.[43] The proposed national requirements, which would be implemented through NPDES permits, would establish national requirements applicable to the location, design, construction and capacity of cooling water intake structures at these facilities by setting requirements that reflect the best technology available for minimizing adverse environmental impact. AEPCO will not be subject to this rule.

ii. Cross-State Air Pollution Rule ("CSAPR"), 40 C.F.R. 97.401 to 97.735

On August 8, 2011, EPA finalized CSAPR, 76 FR 48208, requiring states to significantly improve air quality by reducing power plant emissions that contribute to ozone and/or fine particle pollution in other states. CSAPR requires a total of 28 states to reduce annual SO_2 emissions, annual NO_X emissions and/or ozone season NO_X emissions to assist in attaining the 1997 ozone and fine particle and 2006 fine particle National Ambient Air Quality Standards.[44] CSAPR is currently stayed by the D.C. Circuit Court of Appeals. AEPCO is not subject to this regulation, because Arizona is not one of the states regulated by CSAPR. Currently, the Clean Air Interstate Rule is in effect; however, this rule also does not include Arizona.

iii. New Source Performance Standards for CO_2 for New Power Plants, 77 FR 22392

EPA proposed NSPS for Greenhouse Gas Emissions: Electric Utility Generating Units, 77 FR 22392, on April 13, 2012. These standards would require *new* fossil fuel-fired EGUs greater than 25 MW to meet an output-based standard of 1,000 pounds of CO_2 per megawatt-hour (lb CO_2/MWh), based on the performance of widely used natural gas combined cycle technology.[45] AEPCO will not be subject to this rule, as the rule regulates only new stationary sources and AEPCO is an existing source.

[43] NPDES Cooling Water Intake Structures at Existing Facilities and Phase 1 Facilities, 76 Fed. Reg. 22174, 22174 (proposed Apr. 20, 2012).
[44] Cross-State Air Pollution Rule, 76 FR 48208, 48208 (Aug. 8, 2011) (to be codified at 40 C.F.R. 97.401 to 97.735).
[45] Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Utility Generating Units, 77 Fed. Reg. 22392, 22392 (proposed Apr. 13, 2012).

7. Additional Requests

i. Commissioner Newman's request to evaluate why renewable could not be an appropriate substitute for load following units like Steam 2 and Steam 3 at Apache Generating Station

Renewables such as solar or wind are not appropriate substitutes for load following units, because they cannot function on a 7 by 24 by 365 basis as do gas- or coal-fired units such as ST2 and ST3. Large-scale solar and wind resources are limited in output to particular times of the day and must be augmented—normally by gas-fired units—so as to assure continued electricity output at times when the sun does not shine or the wind does not blow.

ii. Commissioner Newman's request to estimate what the cost of solar would be to replace 350 MW of coal and/or natural gas generation at Apache Generating Station

AEPCO has prepared a very high-level estimate of the costs associated with installing 350 MW of solar PV at Apache Generating Station. Our estimated cost assumes the land used is currently owned by AEPCO and is suitable for such an installation.

PV cells capacity	350 MW (peak)
Land needed	1,750 acres
# of PV cells	3,045,000
Average daily output	62,000 kW/day
Yearly output	545,000 MWh/Year
Price to install solar	$950,000,000

The estimate is only the installation costs associated with 350 MW of solar and does not include any operational or maintenance costs. Further, as mentioned previously, the current capacity of ST2 & ST3 is dispatchable, whereas this PV power would not be dispatchable. Therefore, an additional and very large expense would be required to maintain ST2 and ST3 (or some other resource like a purchased power agreement) on constant standby status so as to assure the 7 by 24 AEPCO capabilities which are required to meet member and their retail members' loads.

To place the $950 million estimated solar capital cost in context, that is about 450 percent more than all of AEPCO's current fair value rate base of approximately $212 million as determined by the Commission in AEPCO's last rate case. Obviously, that cost is not something AEPCO could finance—nor something its members could afford.

This is not to say that at some time in the future when AEPCO needs new, additional resources to meet the needs of its members that renewables will not be considered. The point here is that renewables/solar are not an appropriate or cost-effective substitute for ST2 and ST3.